DUKE ENERGY

2018

2018 IRP & AVOIDED COST

DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS

2018 SOUTH CAROLINA EX PARTE BRIEFING

- IRP Process Overview
- Key IRP Inputs
  - Load Forecast
  - Energy Efficiency (EE) / Demand Side Management (DSM)
  - Renewables
  - Natural Gas Prices
  - Retirements
  - Nuclear Assumptions
  - Battery Storage
  - Integrated System and Operations Planning (ISOP)
  - DEP Short-Term Need
- Base Case Selection & Analysis
- IRP Key Takeaways
- Avoided Cost Discussion

- 2018 DEC SC IRP filing: https://dms.psc.sc.gov/Attachments/Matter/0cf6f148-eb5e-45bd-a401-14aee8a148f8

- 2018 DEP NC IRP filing: https://starw1.ncuc.net/NCUC/PSC/PSCDocumentDetailsPageNCUC.aspx?DocumentId=5722b14c-21eb-4a59-9522-91a5bf1cdec0&Class=Filing

It is expected that the DEP SC IRP filing will contain the same information presented in the NC IRP

IRP Process Overview

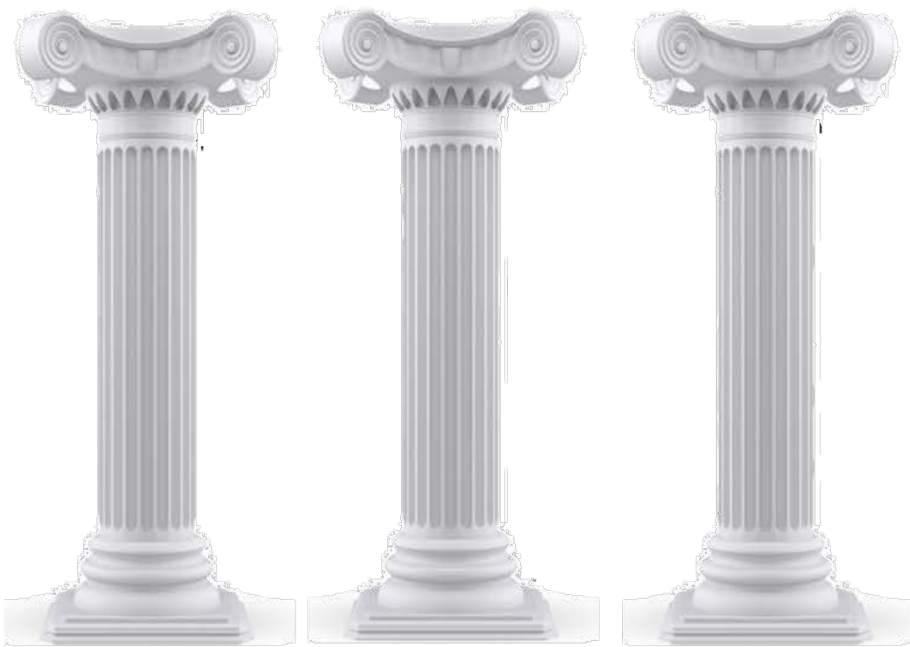
NCUC

FERC / NERC

PSCSC

EPA

Primary Planning Objectives



Environmental (Increasingly Clean) | Financial (Affordability) | Physical (Reliability)

Growth in Customer Consumption

- Changes in Load Forecast
- Impacts of Energy Efficiency (EE)
- Impacts of Renewable Energy

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Resource Retirements

- Plant Retirement
- Purchase Power Contract Expiry

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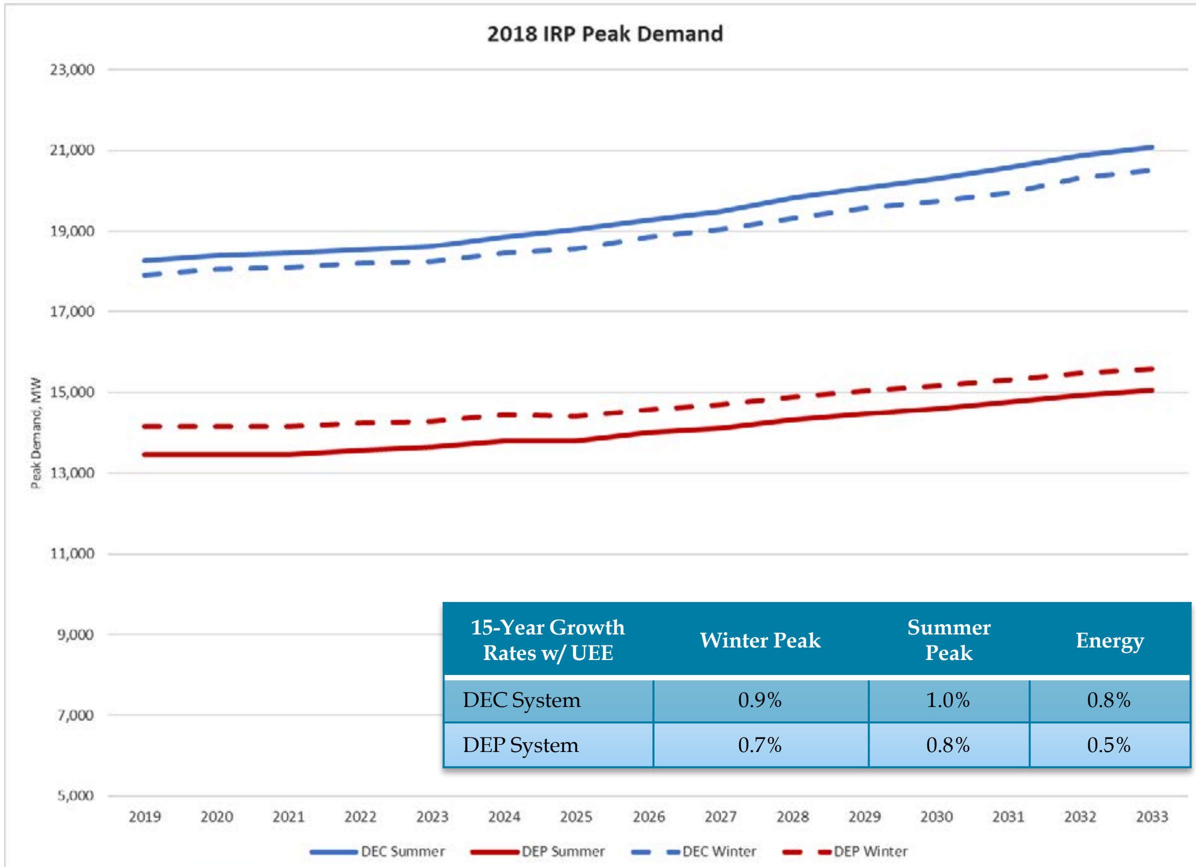
Resource Need

- Load Resource Balance
  - Reserve Margin
- Non-conventional Resources
- Remaining Resource Gap

2018 Resource Plans

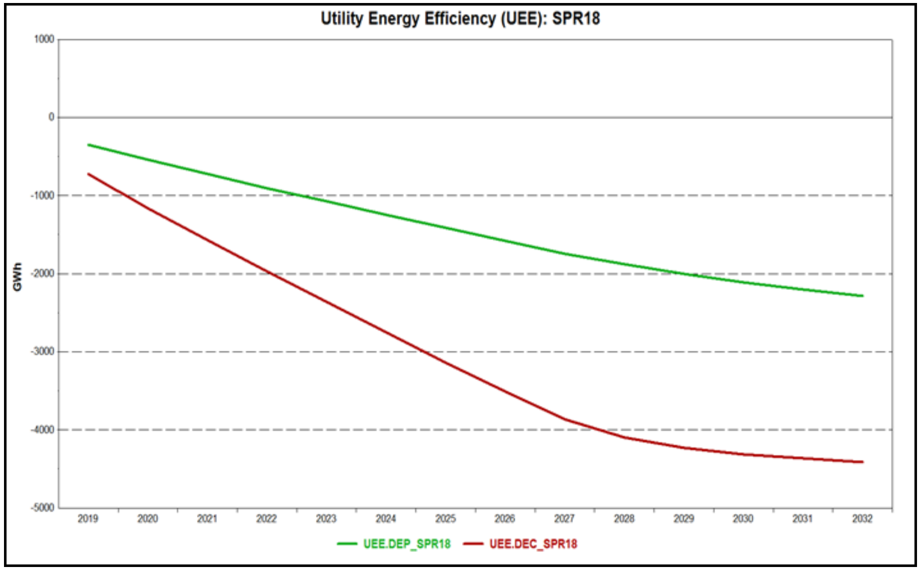
- Resource Plans
  - Base Plan w/ Carbon Tax
  - Base Plan w/o Carbon Tax

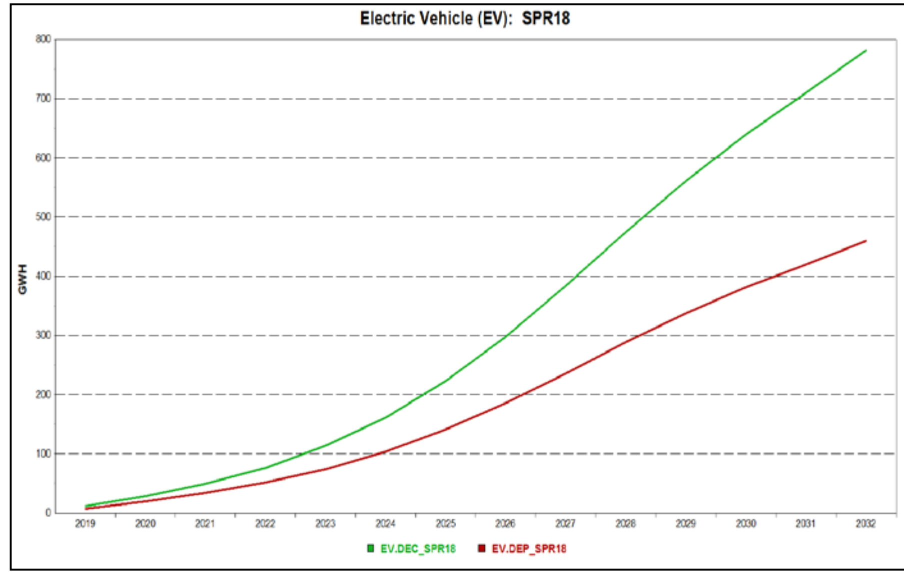
Inputs to IRP



15-Year Growth Rates w/ UEE	Winter Peak	Summer Peak	Energy
DEC System	0.9%	1.0%	0.8%
DEP System	0.7%	0.8%	0.5%

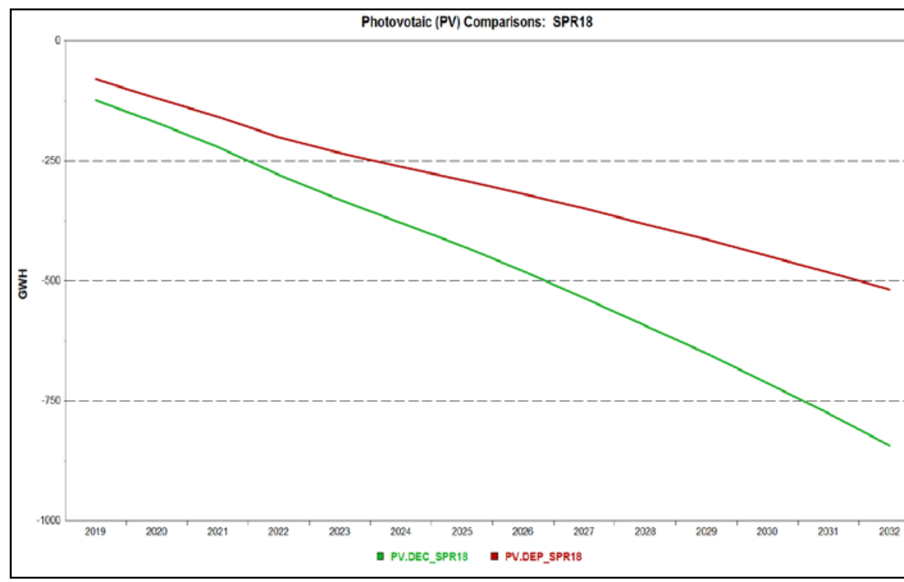
Both DEC and DEP continue to have modest peak demand growth rates of 1% or less





For both DEC and DEP, the 2018 IRP energy sales forecast saw the following impacts:

- Nearly 4,000 GWh of UEE (net of roll-off)
- Over 1,000 GWh of EV Load Growth
- Over 1,200 GWh of NEM PV Growth



Residential Customer Programs

Energy Efficiency

- Energy Assessments
- Energy Efficiency Education
- Multi-Family Energy Efficiency
- My Home Energy Report
- Income-Qualified Energy Efficiency and Weatherization Assistance
- Smart$aver® Energy Efficiency
- Energy Efficient Appliances and Devices

Demand Side Management

- Power Manager

Non-Residential Customer Programs

Energy Efficiency

- Non-Residential Smart $aver® Prescriptive
- Non-Residential Smart $aver® Custom
- Non-Residential Smart $aver® Custom Assessment
- Non-Residential Smart $aver® Performance Incentive
- Small Business Energy Saver

Demand Side Management

- PowerShare®
- EnergyWise[SM] for Business

Residential Customer Programs

Energy Efficiency

- Energy Assessments
- Energy Efficiency Education
- Multi-Family Energy Efficiency
- My Home Energy Report
- Neighborhood Energy Saver (Low-Income)
- Smart $aver® Energy Efficiency
- Residential New Construction
- Save Energy and Water Kit

Demand Side Management

- EnergyWise℠ Home

Non-Residential Customer Programs

Energy Efficiency

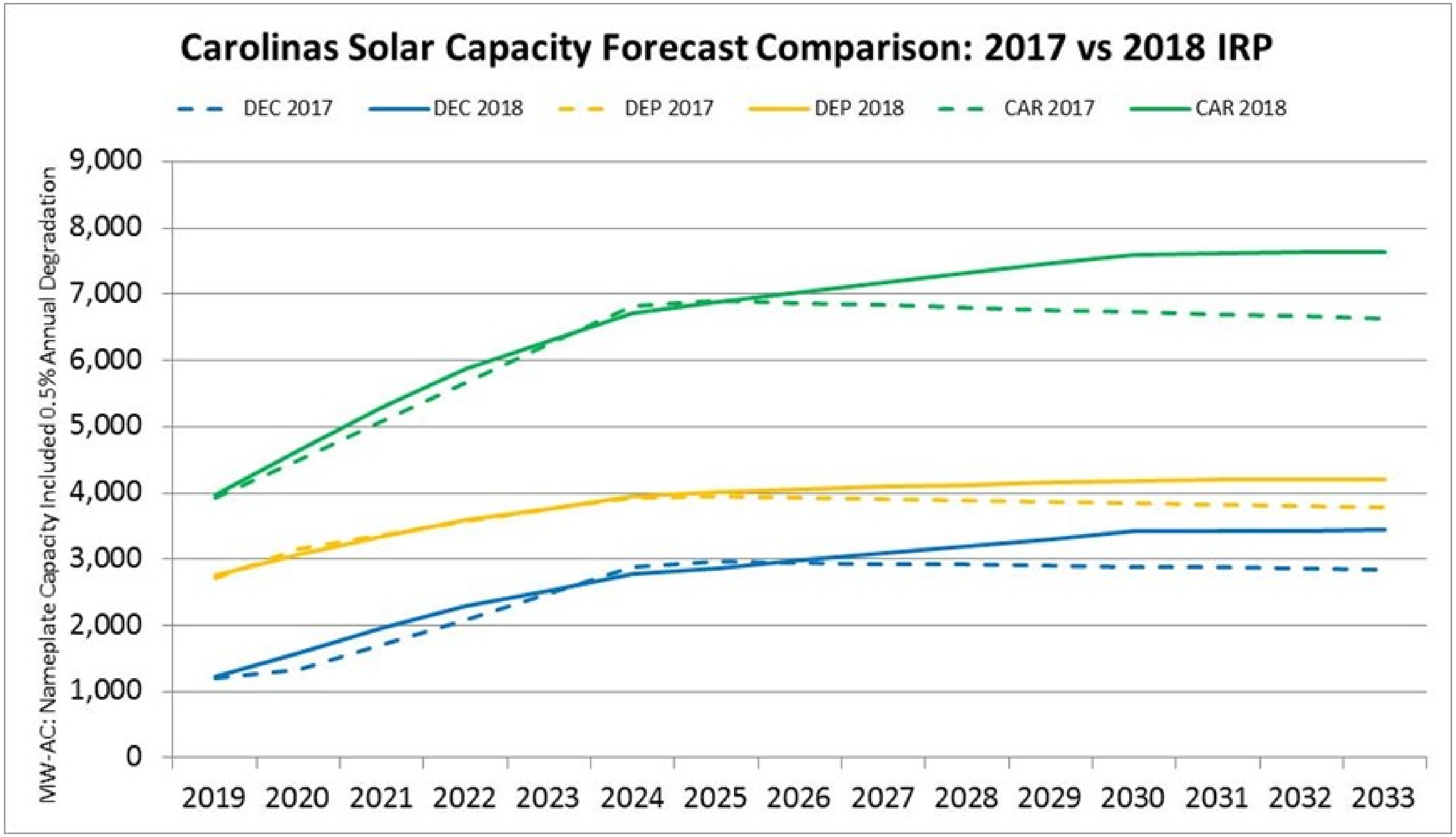
- Non-Residential Smart $aver® Energy Efficiency Products and Assessment
- Non-Residential Smart $aver® Performance Incentive
- Small Business Energy Saver

Demand Side Management

- CIG Demand Response Automation
- EnergyWise℠ for Business

Combined Residential/Non-Residential Customer Programs

- Energy Efficient Lighting
- Distribution System Demand Response (DSDR)

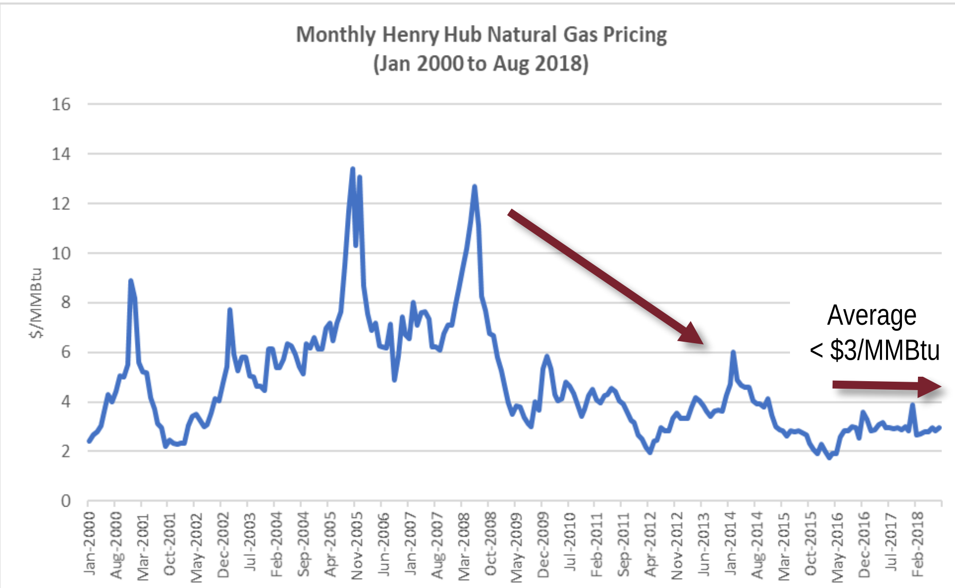


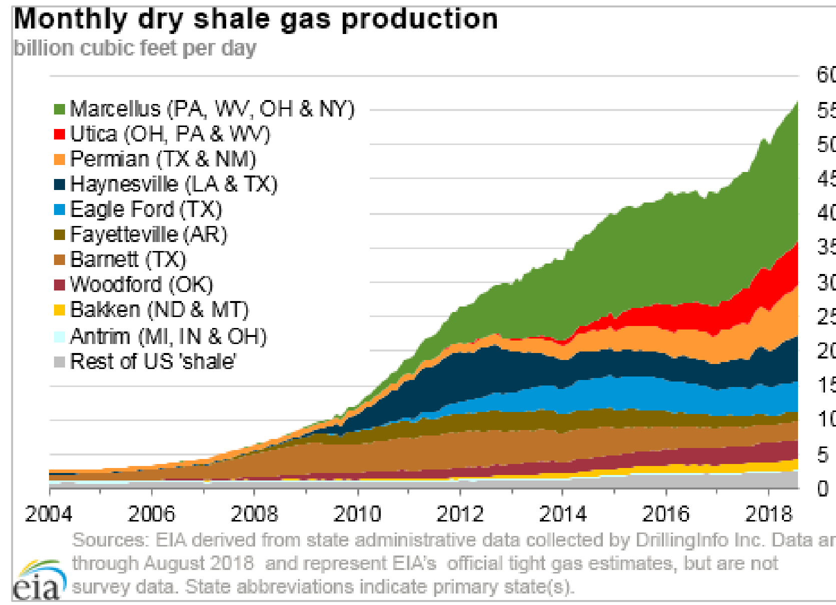
- Irrespective of the installed location of solar resources, solar energy serves the needs of both SC and NC customers on the DEC and DEP systems
- Impacts of SC DERS and HB 589 compliance plus incremental solar included
- Nameplate solar including 0.5% annual degradation:
  - DEC increases from 1,218 MW (2019) to 3,440 MW (2033)
  - DEP increases from 2,758 MW (2019) to 4,199 MW (2033)

- Solar Capacity Value[1]
  - The 2018 IRP demonstrates the declining capacity value of solar as penetration increases. Winter capacity value declines to less than 1% of nameplate over time.

	Incremental Solar MW	Cumulative Solar MW	Winter Capacity Value	Summer Capacity Value	Incremental Solar MW	Cumulative Solar MW	Winter Capacity Value	Summer Capacity Value
	DEC				DEP			
Existing + Transition	840	840	0.9%	33.6%	2,950	2,950	0.6%	12.4%
Increment 1	680	1,520	0.9%	33.4%	160	3,110	1.0%	14.7%
Increment 2	780	2,300	0.8%	26.5%	180	3,290	1.0%	13.8%
Increment 3	780	3,080	0.5%	22.5%	160	3,450	0.8%	10.6%
Increment 4	420	3,500	0.4%	17.4%	135	3,585	0.8%	10.0%

[1]Winter and Summer capacity values based on weighted average of fixed and tracking PV solar results presented in the 2018 IRP





- Shale gas production continues to rise while natural gas prices have averaged less than $3/MMBtu over the last two years and less than $3.50/MMBtu for almost a decade.
- Compared to the 2017 IRP, the average 15-year natural gas price has declined by approximately 4% with the 10-year market price for Henry Hub gas at $2.85 per MMBTU.

DEC Planning Assumptions – Unit Retirements				
Unit & Plant Name	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Allen 1 - 3	604	585	Coal	12/2024
Allen 4 & 5	557	542	Coal	12/2028
Lee 3	173	160	NG	12/2030
Cliffside 5	546	544	Coal	12/2032
Total	**1,804**	**1,847**		

DEP Planning Assumptions – Unit Retirements				
Unit & Plant Name	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Expected Retirement
Asheville 1 & 2	384	378	Coal	11/2019
Darlington CT (1-4, 6-8, 10)	514	379	NG / Oil	12 / 2020
Blewett CT	68	52	Oil	12 / 2024
Weatherspoon CT (1-4)	164	124	NG / Oil	12 / 2024
Roxboro 1 & 2	1,053	1,047	Coal	12 / 2028
Roxboro 3 & 4	1,409	1,392	Coal	12 / 2033
Total	**3,592**	**3,372**		

**All retirement dates are subject to review on an ongoing basis. Dates used in the 2018 IRP are for planning purposes only, unless already planned for retirement.*

- DEC and DEP are working within the framework established by the Nuclear Regulatory Commission (NRC) to evaluate the potential for subsequent license renewals (SLR) of its nuclear units.
- SLR would give the Companies the option to operate up to an additional 20 years.
- Base IRP assumption is that all existing nuclear generation will receive an SLR.
  - A sensitivity was performed assuming SLRs were not pursued for any nuclear assets.
- In the longer term, Small Modular Reactors (SMRs) were allowed to be selected in most cases as an option for reducing carbon emissions in carbon constrained cases.

- Battery storage was considered as an input into the portfolio development process.
  - 140 MW and 150 MW of battery storage in DEP and DEC respectively was included as a placeholder for future assets to provide operational experience on the Companies' systems
  - These placeholders represent a limited amount of energy storage that have the potential to provide solutions for the transmission and distribution systems with the possibility of simultaneously providing benefits to the generation resource portfolio.
- For the 2018 IRP, grid-tied, controllable 4-hour battery storage technology was included in the expansion plans.
  - Capacity contribution placeholders were based on an EPRI study which provided a range of methodologies for calculating the capacity value of 4-hour battery storage.[1]
- The model assumes real-time control of when the battery storage is dispatched to, or charged from, the system in order to maximize system benefits.
- An additional sensitivity was included where a 4-hour battery replaced a Combustion Turbine in the mid to late 2020s in both Companies.

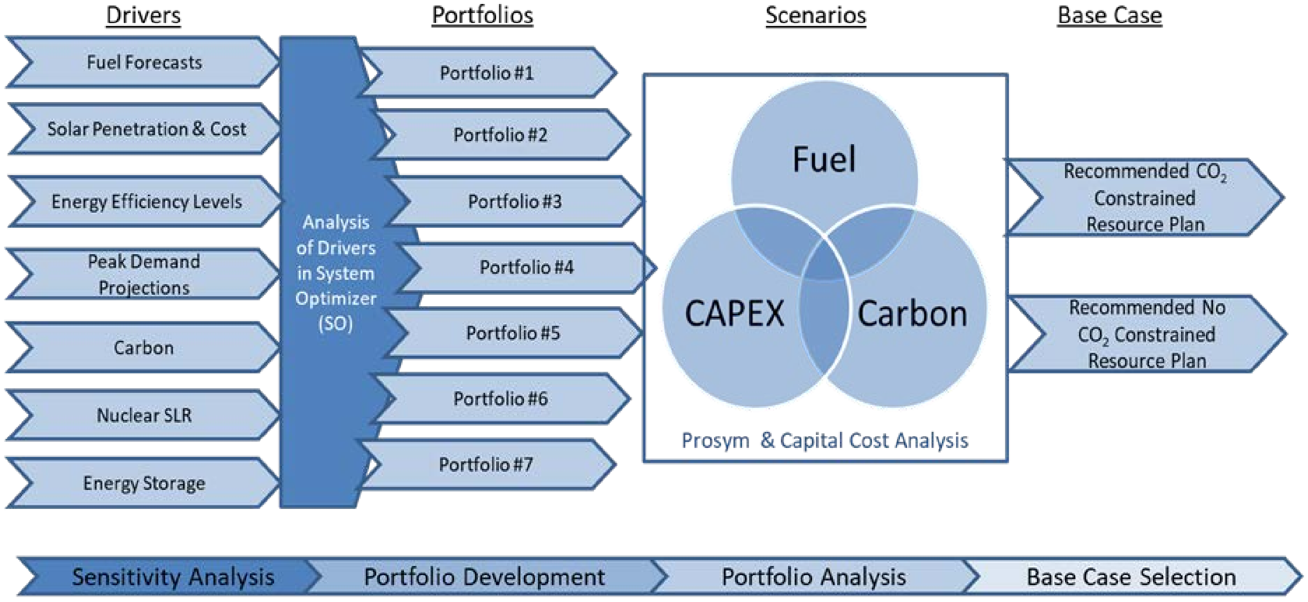
[1]EPRI; "Technical Update: Evaluating the Capacity Value of Energy Storage" (E. Lannoye & E. Ela, December 2017)

- Recognition that the traditional methods of utility resource planning must be enhanced to keep pace with changes occurring in the industry.
- The planning tools that have been used in the past are limited in their ability to value some aspects of newer technologies.
- Developing additional toolsets to be able to identify the locational value of distributed generation sources, as well as, more tightly link distribution plans to the bulk power plans.
- Develop modeling capability to identify the operation impacts of intermittency of some supply resources at the sub-hourly level.
- While models are not yet perfected, Duke Energy is making reasonable estimates for real-time system impacts of integrating intermittent renewable resources .

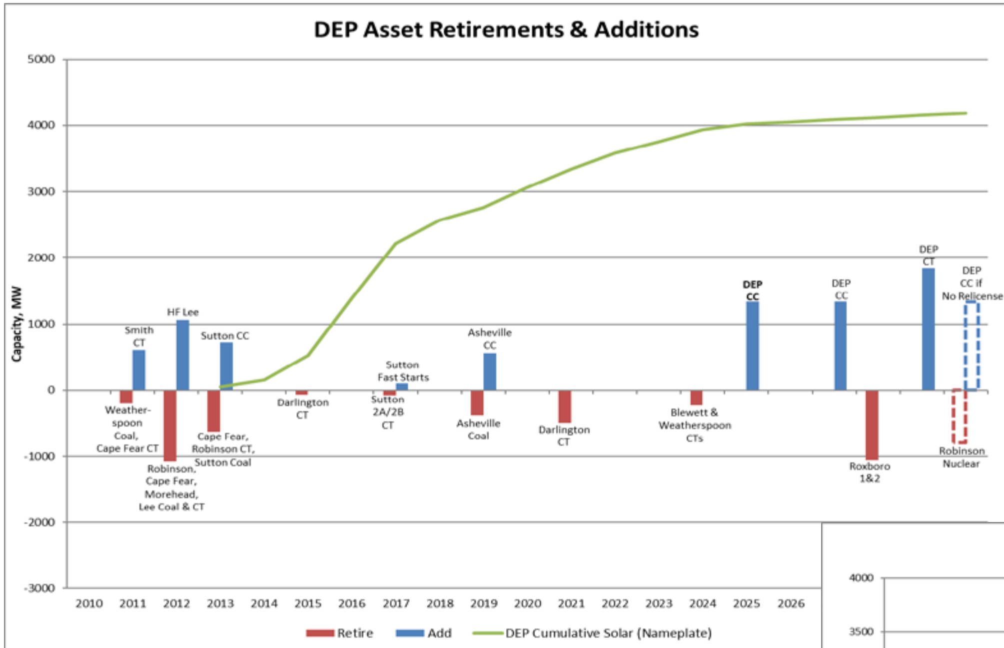
- DEP requires approximately 600 MW growing to nearly 2,100 MW of new generation in the 2021 to 2024 timeframe.
- The need for new resources is driven by existing purchase power contract expirations (1,472 MW), CT retirements (746 MW), and an increase in the winter peak demand forecast of approximately 600 MW in 2019.
- To meet the need, DEP is seeking to prudently renew existing purchase power contracts or replace them with similarly situated resources through a targeted market solicitation that began in mid-August 2018.
- These resource requirements are identified as “Undesignated Short-Term Market Purchases” in the 2018 IRP

Base Case Selection & Analysis

Process for Development and Selection of Base Cases

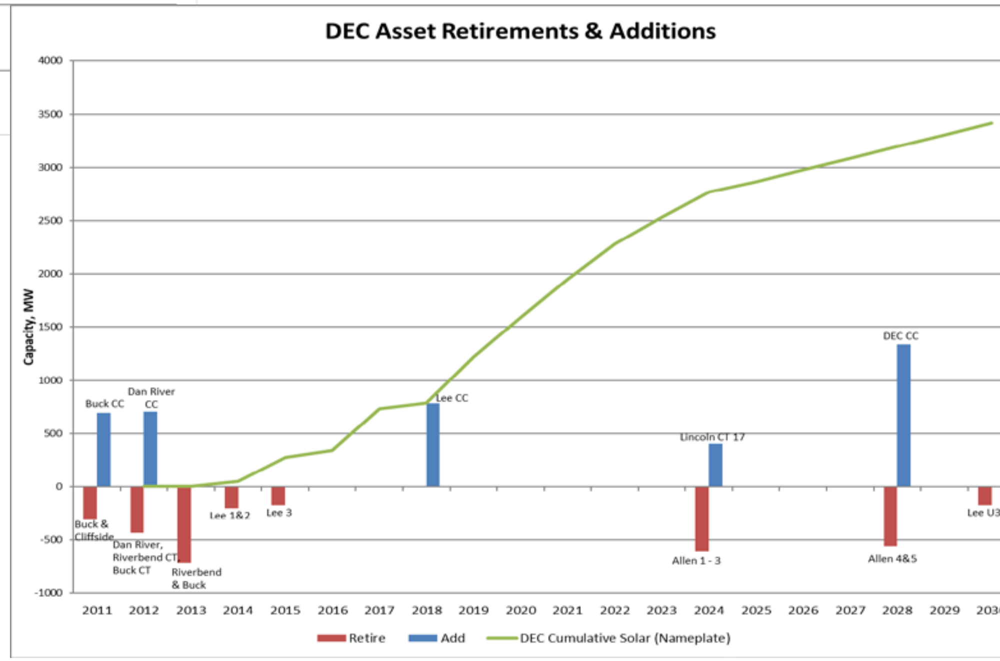


- Multiple drivers were evaluated individually in the sensitivity analysis using System Optimizer (SO) to develop expansion plans
- Similar expansion plans were grouped to develop seven Portfolios that were further analyzed using PROSYM to determine system production costs
  - Portfolios were analyzed under varying fuel, carbon tax, and capital cost scenarios
- "CO_2 Constrained" and "No CO_2 Constrained" base resource plans were selected based on the scenario analysis



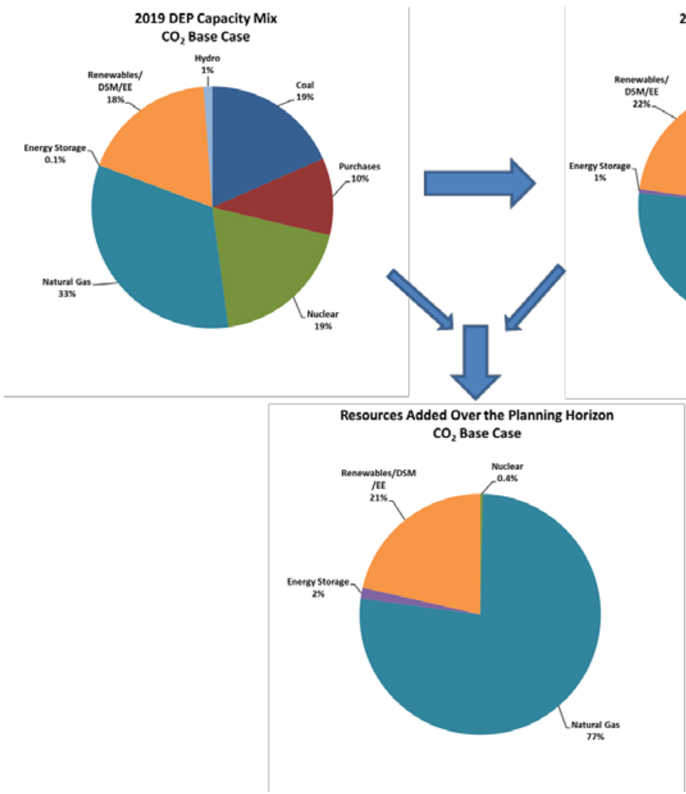
As older assets retire and load continues to grow in DEP, the need for new generation is required in the mid 2020 timeframe.

Opportunities for new generation resources are limited in DEC without an acceleration of asset retirements or an increase in load growth.

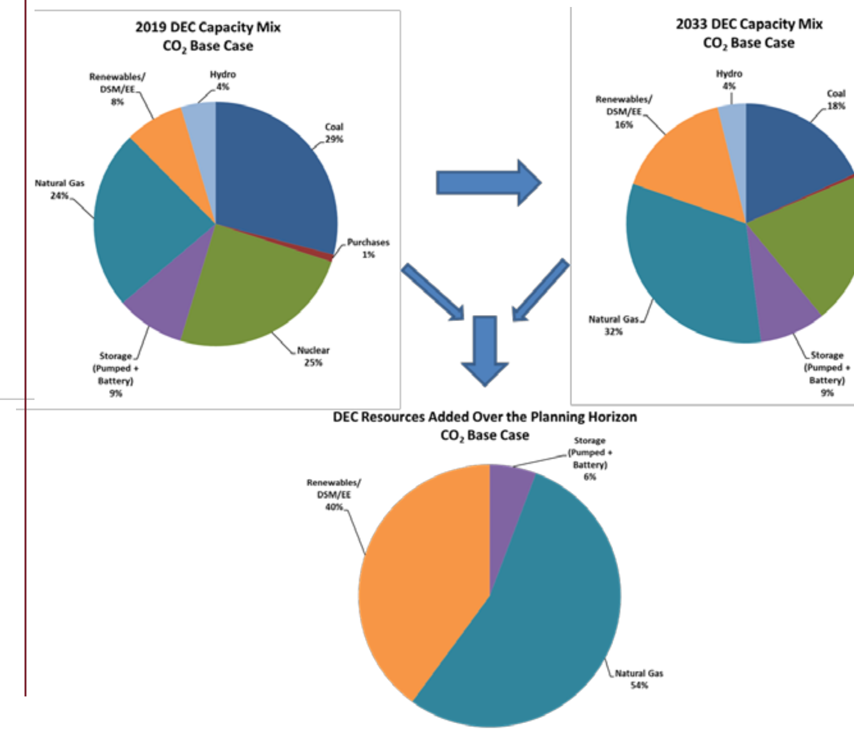


- Carbon Constrained base case capacity mix

DEP Capacity Mix

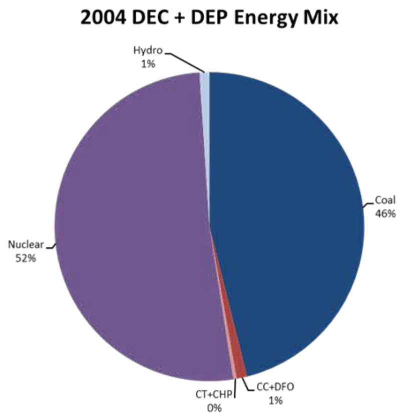


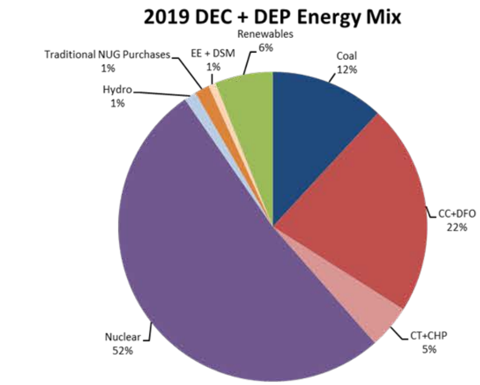
DEC Capacity Mix

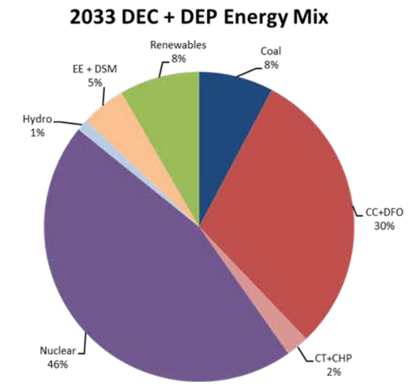


- Carbon Constrained base case energy mix

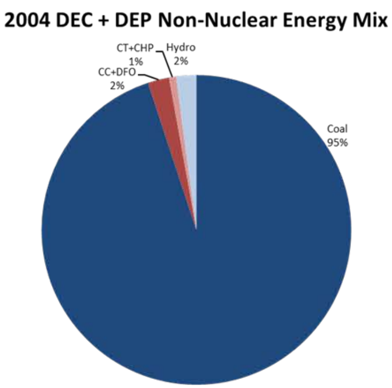
Total Energy

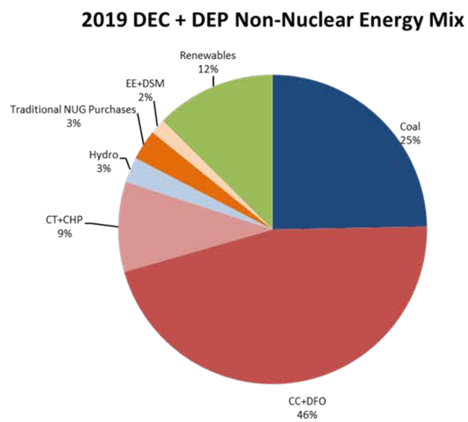


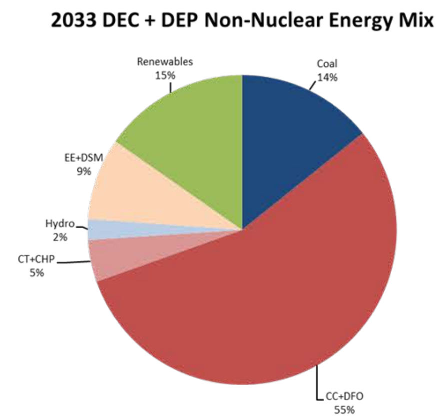




Non-Nuclear Energy







Over the last 15 years, there has been a significant shift in how energy is generated in the Carolinas;

Over the next 15 years, that shift continues

- First Generation Needs in DEP & DEC
  - DEP's short-term needs are expected to be met by some existing purchase power resources whose contracts are expiring, along with other similarly situated assets.
  - Combined Cycle generation continues to be the preferred technology for meeting the capacity and energy needs in DEP and DEC in the mid 2020 timeframe.
  - Continued decline in capital costs, improvements in efficiency and flexibility, continued low natural gas prices, and reduced carbon emissions contribute to the appeal of CC resources.

- Existing nuclear assets
  - Approximately 50% of the Companies energy comes from carbon and emission free nuclear generation with minimal fuel cost
  - The Company is working within the framework established by the NRC to evaluate license renewals
  - Current projections show that maintaining the option to continue operating the Company's existing nuclear fleet provides value for the Company and it's customers.

- Solar Energy
  - Duke is a national leader in solar and has aggressive plans to continue to increase the amount of solar energy on its DEC and DEP systems through the addition of over 2,200 MW and 1,440 MW of nameplate solar capacity over the planning horizon.
  - However, while valuable energy is provided, increasing levels of solar resources will provide little capacity contribution.

- Battery Storage
  - Initial deployments will seek to optimize location specific transmission and distribution benefits while co-optimizing generation and ancillary service benefits dependent on the specific T&D use case.
  - If deployed and operated appropriately, battery storage provides additional value as intermittent energy resources increase on the system, particularly in DEP.
  - Future storage value will be dependent on significant cost declines consistent with IRP assumptions.
  - Initial deployments will provide valuable implementation and operational experience.
  - Advancements in modeling capabilities (sub-hourly / distribution level) will help improve the evaluation of these types of distributed technologies.

- In summary, at the end of the planning horizon the companies will have:
  - Added approximately 2,700 MW in DEC and 1,650 MW in DEP of nameplate solar, EE and DSM resources;
  - Added over 3,500 MW in DEC and 5,900 MW in DEP of natural gas technology;
  - Taken critical steps to extend licenses on its nuclear fleet; and
  - Deployed a growing number of battery resources…
- …All resulting in diverse portfolios insulating customers from fuel and technology cost uncertainties into the future.

PURPA Avoided Cost

- Congress enacted the Public Utility Regulatory Policies Act (PURPA) in 1978 and FERC enacted PURPA regulations
- Cogeneration and renewable facilities less than 80 MW are defined as "Qualifying Facilities" or "QFs" and have the right to put power to the utility and its customers
- PURPA creates an obligation for utilities to purchase, and customers to pay for, private sector QF power put onto the grid
- The intent of PURPA is to leave customers indifferent to QF power vs. the utility's alternative generation with a value based upon the utility's "avoided cost." This principle is referred to as the "indifference principle" or the "but for principle."

- As approved by this Commission and the NCUC, DEC and DEP have consistently used the "peaker methodology" to determine avoided capacity and energy costs for setting the avoided cost rates paid to QFs.

- The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost that can be avoided by a QF.

- The peaker methodology assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a peaker CT plus the variable marginal energy costs of running the system will produce the marginal capacity and energy cost that a utility avoids by purchasing power from a QF.

- **Avoided energy costs** represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt hour ($/MWh), include items such as avoided fuel, environmental, and avoided variable operation and maintenance ("VOM") costs.

- **Avoided capacity costs** represent the fixed costs associated with construction, financing and staffing of a CT. The fixed costs are the annual costs incurred to have production capacity available and dispatchable on demand. These costs do not depend on the actual use of the CT but rather the costs to build the CT and have it available to meet customer demand.

- The Companies' IRPs are used as the basis for determining the future value of QF energy and capacity.

Capacity

- Under PURPA, utilities should not require their customers to pay for QF capacity unless there is an associated capacity cost to be avoided
- Consistent with the Companies' 2018 IRPs, DEC's first capacity need is 2028 (combined-cycle addition)
- DEP's first capacity need is 2020 (short-term market purchase)

Energy

- The value of marginal energy starts with the IRP no-carbon base resource plan
- The base plan is compared to a plan that adds a "no-cost" 100MW resource in every hour
- The production cost difference between the two plans produces the variable energy cost savings available to QFs
- The past decade has seen declining fuel prices resulting in significant reductions in the value of marginal energy

- Intermittent QF resources produce avoided energy value for customers.
- Depending on the nature of the resource may, or may not, produce capacity value.
- Distribution connected QFs have the ability to reduce transmission related line losses.
- Depending on the specific location of the QF resource there is a potential to either increase or decrease the need for transmission and distribution capacity.
- However, intermittent QF resources also create integration costs that arise from increased real-time system regulation and balancing reserve requirements.

- QFs have the potential to provide customers with a valuable source of clean, carbon-free generation.
- The avoided cost calculation can sometimes be complex and multi-faceted and is often debated by stakeholders.
- However, the core "indifference principle" requiring customers to pay no more than they otherwise would have for traditional generation serves as a central tenet in the determination of avoided cost rates.